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Curtailment of renewable generation: Economic optimality and incentives

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Abstract

The loss from curtailing generation based on renewable energy sources is generally seen as an unacceptable solution by the public. The main argument is that it is a loss of green energy and an economic loss to curtail generation with near zero marginal costs. However, this view could lead to overinvestment in grid infrastructure and underinvestment in renewable energy sources. This article argues that some curtailment of fluctuating (variable) generation is optimal. We address the possible contributions to total curtailment from involuntary and voluntary curtailment. The costs of curtailment in terms of lost generation is discussed based on market price and support levels including the rationale for compensating generators for losses. The extent of actual curtailment is illustrated by examples from different global markets. In general, both the value of the curtailed energy and the amount of curtailed energy relative to total fluctuating generation is low but rising. Single generators may be affected considerably if insufficient compensation measures are in place. In the future, optimal curtailment will increase along with an increased share of fluctuating renewable generation. Extending renewable generation comparatively cheaply can be achieved by the installation of additional capacity at offshore locations until optimal curtailment levels are reached.

Keywords: Electricity prices; Fluctuating generation; Renewable energy; Network integration; Network regulation

1. Introduction

The large investments in generation units based on renewable energy sources (RES) during the last years have increased the focus on integration costs of fluctuating generation. A part of these costs are related to the risk that in some hours, too much electricity is generated from these sources relative to network capacities and demand levels. Avoiding curtailment of this generation would require investing in network capacity including international interconnection and storage solutions which are very costly if used for few hours annually. Already today, more frequent occurrences of curtailment for renewable generators are observed in areas with high shares of fluctuating generation such as wind (Fink et al., 2009). The question whether to avoid this curtailment or not is debated increasingly. If deemed acceptable, different criteria can be taken as a decision basis (e.g. Huang/Liu, 2011).

An apparent option to minimise integration costs is to accept generation curtailment due to network constraints or market reasons. At first sight, curtailment of renewable generation might seem as a loss that should be avoided, but in certain situations, curtailment to a limited extent is an optimal solution with regard to total costs of providing electricity. This is illustrated in a number of papers dealing with transmission constraints, capacity investment and security issues, see e.g. (Acharya et. al., 2009, Rious et. al, 2010., Ela, 2009).

Curtailment occurs today both as a consequence of constraints in distribution and transmission grids, but also as a precaution measure to secure stability of the system when there is high risk that large amounts of wind capacity might fall out during storms or as a consequence of network faults. This has been observed in areas in the US (Texas), in Spain and in Germany as well as in smaller areas in other countries. From the generator point of view, the effect of curtailment is independent of the underlying causes. Therefore, all the different types of curtailment affecting renewable generators are addressed in this article.

This paper is structured as follows. In section 2 we first provide an overview of the different causes and types of curtailment and categorise them with regard to underlying reasons. The comparison identifies a) arguments for including curtailment as an option to reduce costs of integrating large amounts of variable renewable generation and b) incentives that could be used to induce appropriate voluntary curtailment behaviour. From this, the question about optimality under both voluntary and involuntary curtailment and arguments for compensation arises. This is why we turn towards these topics in a next step. On the one hand, full absorption of all generation can lead to excessive network extension costs. On the other hand, compensation to generators is a key topic if we will induce appropriate investment in network reinforcement.

Section 3 analyse the behavioural aspects of voluntary and in-voluntary curtailment and the incentives that affect this behaviour.

The following section 4 presents quantitative evidence for both voluntary and involuntary curtailment. A highlight is cast on the coincidence of curtailment and low market prices. Next, section 5 provides a discussion on total cost arising from all curtailment types and whether they are based on the short-term value of the power. This is related to benefits in terms of investment and operation savings. Finally, section 6 contains concluding remarks on the possibility of optimal curtailment and the necessary incentives to support optimal behaviour of both generators and networks.

2. Categories of curtailment

In this section, we categorise the types of curtailment based on the situation in which they occur and the rationale for voluntary and involuntary curtailment. We define curtailment as an instance when a generation unit produces less than it could due to its own marginal cost characteristics.

Network investments become increasingly dependent on the localisation of generation capacity also at distribution levels. Considering that simultaneous peak generation of different technologies in an area occurs only for a few hours per year, the marginal network investment per generated unit can turn out to be quite high. This stresses the importance of the localisation decision for this type of generation capacity. The curtailment of generation in hours with constraints can serve as an incentive for investors to find locations with least risk of curtailment. Ochoa et. al. (2010) examine the distribution network capacity with variable generation sources in combination with active control and find that accepting 2% curtailment doubles the variable generation capacity that can be accommodated in a distribution grid. The location decision of new fluctuating generation, network tariffs and regulation of Distribution

System Operators (DSOs) is discussed in Ropenus et. al. (2011), also pointing to the potential incentives from curtailment and compensation rules.

International interconnection capacity relative to national generation and fluctuating generation capacities is very different among EU countries. This constraint can in some instances create a curtailment risk. It applies both in the general excess generation situation, but also to emergency situations when more flexible generation reserves are required online and interconnection capacity to other areas cannot fulfil this reserve requirement. However, avoided curtailment is probably a minor benefit of additional interconnection capacity.

Table 1 distinguishes four reasons for curtailment. We will address them separately in the following. As shown by Burke and O'Malley (2010), it is possible that the different types of curtailment are correlated in time. If there is a risk of curtailment due to overall excess generation, there is probably also curtailment due to network constraints. The following table gives an overview of the different reasons and main features. Column one and two distinguishes voluntary and involuntary occurrences of curtailment and the responsible entity. Column three lists economic rationales for allowing curtailment and column four suggest the extent and responsible for compensation to generators.

Table 1 Categories of curtailment situations

Reason	Voluntary	Involuntary	Rationale	Possible compensation
Network constraints	Accepted in contracts – (at time of connection)	Short term DSO-controlled generation reduction	Avoid overinvestment in transmission and distribution capacity, extension delays	DSO or TSO compensate based on market price and/or subsidy (legislation)
Security	Specialised market	Max. generation limits for a number of consecutive hours, mainly enforced by TSO	Reduce reserve capacity costs/ /dynamic reserve dependent on variable generation	Separate market or compensation from TSO/grid users based on legislation
Excess generation relative to load levels	Low or negative power market prices induced	Generation limits enforced by TSO	Highest marginal costs generators should be curtailed if market fails	Compensation by TSO based on subsidy only to provide incentive for voluntary curtailment (legislation) no compensation for involuntary curtailment
Strategic bidding	Manipulate prices	-	Profit from exercise of market power	-

Network constraints

Curtailment due to network constraints can be both voluntary and involuntary, but most focus has hitherto been on the involuntary curtailment and related problems regarding connection of new renewable generation capacity. In many countries, RES producers enjoy priority network access at their nominal capacity, also referred to as firm access. We distinguish *voluntary curtailment* from involuntary curtailment by an ex-ante agreement between the RES investor and the network owner specifying the rules for amount of curtailment and possible compensation. In addition, the RES investor needs to sign this agreement voluntarily, i.e. network connection may not be conditional on the existence of such an

agreement. In practice, this could have several effects, e.g. a) lower connection charges than under the mandatory regime if the RES unit agrees to connect at a different network node with possibly higher curtailment, or b) connection to a point with less expected curtailment than in the mandatory benchmark situation. The additional costs associated with the connection to a different, 'less-curtailment' node could be borne by the benefitting RES investor. *Involuntary* curtailment can take place temporarily due to delays in infrastructure investment relative to generation capacity. Building wind capacity can be completed in time spans from months to a few years, whereas investment in new transmission lines can have delays of up to 10 years. Involuntary curtailment caused by permanent network constraints could be combined with an obligation for the network owner (DSO or TSO) to compensate the generator at least partly for the loss incurred. This is important in order to provide an incentive for the network owner to build more capacity, and do it at a speed that balances the costs of network investment with the value of curtailed energy represented by the compensation payments. This point holds if the network operator is not legally obliged to build the additional capacity to avoid curtailment. Grid reinforcement is only rational when expected curtailment exceeds a certain level and can also be subject to lump-sum investment characteristics of network extensions. Economies of scale for network investments will reinforce the lumpiness of this investment and contribute to varying levels of curtailment over time.

Voluntary curtailment in networks is mostly associated with investments where the investor directly or indirectly finances the connection lines to the network. For offshore wind projects, this constitutes a considerable part of the total investment amount in some countries. With high costs for offshore cables, the optimal investment in cable capacity is reduced somewhat below the expected annual maximum output of a wind farm (National Grid, 2009). The investor thereby voluntarily accepts some curtailment due to a constraint in his own connection cable. Naturally, there is no compensation associated with this type of curtailment, and it will not show in any statistics. Optimally, the marginal value of expected curtailed energy over the lifetime of the cable should be balanced with the marginal cost of increasing the cable capacity.

DSO and TSO networks are widely regulated entities based on their natural monopoly properties. Especially in Europe, the traditional regulatory approach was to make the connection of new small to medium scale renewable generation capacity in distribution grids mandatory for the DSO. Reaching higher penetration levels, it has been shown that nonfirm connection can lead to a larger amount of installed wind capacity (see e.g. Keane et al, 2007, or Bajor/Jankowski, 2011). Since mandatory connection of renewable generation at full capacity has not always been possible without causing grid problems because of limitations and delays in grid reinforcement, the issue of compensation in curtailment cases has been added to the debate. The interaction between the DSO and the investor in distributed generation (DG) in terms of incentives and revenue has been covered e.g. in the IMPROGRES project (Ropenus et. al., 2009). This report points to the plant location decision as an important decision that depends on regulation and connection policies and affects the interrelated costs between DG and DSO in the specific DSO grid. New plant location decisions also affect the distribution of DG investment over DSO grids with different DG penetration and cost characteristics. For this decision to be efficient, one has to consider the *appropriate cost mechanism* for the DSO to affect DG location decisions. The new investor may be exposed to some costs, for example in the form of curtailment if he invests in an area with high network reinforcement costs. An incentive, for example no or reduced compensation for curtailment, is needed to consider alternative locations where there is less risk of curtailment because marginal network extension costs are lower. Regulated parameters as connection charges and use of system charges can have such effects, but they can only vary within limits approved by the regulator. Setting connection charges, the DSO is able to provide incentives for DG localisation, but this parameter

is often regulated at shallow connection cost that do not account for more widespread network reinforcement costs. An option is therefore to let a curtailment cost serve this purpose. A drawback of this approach is that this cost is quite uncertain as it is a revenue stream loss over the lifetime of the generation investment and depends strongly on changes in the level of compensation. Allowing curtailment with compensation could thus serve a double purpose: a) avoiding overinvestment in grids and b) providing incentives to renewable investors to locate their investments where the reinforcement costs are the lowest. Another aspect is that grid extensions typically require more time than erecting new RES capacity (10 years for overhead lines in comparison to 2-3 years for wind turbines, whereas underground cables are faster to build, but at higher costs). This leads to an inherent risk when planning optimal network extension and curtailment, and it is likely that actual curtailment deviates from the optimal level.

On the negative side of cost interaction, there is a cost element of DSO operation that depends on the support scheme for DG. If the curtailment cost of generation is to be borne partly by the DSO, the curtailment cost are higher under a fixed feed-in tariff. Under a premium or Tradable Green Certificate (TGC) scheme, the power market price tends to be lower at times of curtailment. For this reason, curtailment cost for the DSO is lower as well. This is efficient from an economic point as the cost of lost generation is reflected in the market price at the given point in time.

Network security and inertia

Network security is distinguished from the other cases by the following criterion: if it is not a capacity limit causing the curtailment, but limitations in other factors such as reactive power or risk of fast change in variable generation, we regard the curtailment as due to network security. In practice, simultaneous occurrences of these situations render a clear-cut separation difficult.

Grid faults and scheduled grid maintenance will cause occasional curtailment of primarily generators connected to the distribution grid levels. The DSO should optimally balance the effort to reduce grid faults with the compensation it has to pay to the generators in these cases. Security concerns in relation to possible grid faults and voltage concerns play an important role in determining how much variable generation can be allowed at certain points in the grid. The EirGrid/SONI (2010) study on wind penetration in Ireland illustrates this with regard to frequency concerns in the island system: beyond a penetration of 70%, curtailment might be required if no other measures are taken. Possible mitigation measures are conventional units providing inertia without providing reactive power or emulated inertia by adapting wind turbine control programs.

A separate concern are fast changes in fluctuating generation: curtailment also takes place as a precautionary action in cases where there is a high share of fluctuating generation expected and the system would lose too much capacity too quickly if wind generation shuts down during storms or local network faults spreading. In principle, this is a systems reserves problem and was especially relevant before fault overriding capabilities became a general property of wind turbines in new installations. However, with high shares of wind relative to load nowadays, there are times when the expected reduction of wind generation from forecasts coincides with low demand levels and requires considerable spinning reserves. Therefore, it can be necessary to curtail wind generators in hours ahead of the expected drop in generation (EirGrid/SONI, 2010). As for all reserves, the cost for this is shared among use-of-system charges contributors which can be consumers only or both consumers and generators depending on national legislation.

Excess generation

When the level of variable generation reaches a high penetration, there will be incidents when generation exceeds a certain maximum load that is regarded as an upper border for system stability, e.g. in an island system. The effect of different curtailment thresholds – i.e. the penetration wind power may not exceed – has been quantified for Great Britain by Gardner and Papadopoulos (2012). In a system with a large amount of installed wind power, large amounts of curtailment can be avoided if this threshold can be raised. Spatial leveling effects could provide a similar effect, although this requires distant and large-scale interconnection. Regarding historical data for West Denmark, wind generation exceeded load during 33 hours in 2009 (Grohnheit et. al., 2011). For a considerable larger number of hours, wind generation exceeds the load after “must run” generators. As the share of variable generation sources in the power systems increases with investments to comply with the EU 2020 RES share targets, such excess generation situations will occur in more areas and for more hours.

The involuntary curtailment in this situation is more problematic for the individual RES operator than from a system point of view since the value of the generation and the market price is low with excess generation. Corresponding to this, voluntary curtailment is also more likely to take place, especially if some generators are not receiving production-dependent market support. This situation is further covered in the section: *Voluntary curtailment and optimality* in the next chapter (see Figure 3).

Strategic bidding

In markets that sometimes experience less than perfect competition, there are potential gains from strategic bidding in the market. Directly related to curtailment is capacity withholding from the market to drive up the market price. Withholding generation capacity with low marginal costs only makes sense for society when market prices are low. The largest gain from withholding capacity is at times of high prices because a small capacity at the steep part of the merit-order curve makes a big difference. In such a situation, this form of curtailment to exercise market power leads to socio-economic losses.

3. Voluntary and involuntary curtailment – optimal behaviour and incentives induced by compensation

The focus of the international discussion has been on the involuntary curtailment of renewable generators, namely the lost “green generation” and associated financial losses for curtailed generators. In this section, we provide an overview of the arguments about involuntary, yet socio-economic optimal curtailment. However, there are also situations when generators curtail voluntarily even though they generate at very low marginal costs. The relation to market prices is as follows:

- Involuntary curtailment occurs at all price levels, but more often at low prices
- Voluntary curtailment occurs predominantly at low market prices

Economic behaviour from generators suggests that generation will be held back only when this is profitable. Involuntary curtailment will take place initiated by the DSO or the TSO for the reasons discussed above. We start with optimality in relation to involuntary curtailment and then turn to private and social optimality in relation to voluntary curtailment.

Involuntarily curtailment and optimality

Involuntary curtailment mainly happens due to network constraints as discussed in the previous section. The question is then whether this type of curtailment is optimal with regard to avoiding other costs, mainly investment in network capacity and reinforcement.

From a social point of view, over dimensioning the capacity of both fluctuating generation and network capacity should be avoided. This does not imply that fluctuating generation always has to be lower than consumption. However, if fluctuating generation causes excess generation, this should be reflected in revenue from market prices to reach an optimal investment level for RES units. If local constraints in the grid are expensive to relieve, this should result in some curtailment of generation. This, in return, should provide incentives to network operators to invest only until the costs of expected curtailment are lower than additional network extensions.

Similarly, the investment in interconnection capacity should be based primarily on market price signals. This reasoning means that investment due to low power market prices in excess generation situations should only take place if associated losses correspond to the investment costs of additional network capacity. This implies that network extensions partly depend on power prices and power market design, possibly applying nodal pricing as a basis for network extension calculations (see Joskow/Tirole (2003) for a comprehensive overview on the theory of merchant transmission investment).

Finally, we would like to highlight the difference between involuntary generator and load curtailment. On the load side, it is seldom an option to dimension the grid to sometimes being short of network capacity. However, on the generation side this option is relevant. The main reason is that the value of lost generation corresponds to the marginal power price in the market, whereas the value of lost load for the consumer is much higher. Only when the value of lost load can be maintained at a low level and identified through interruptible connection contracts with large customers, the load curtailment becomes relevant as an alternative to grid extension.

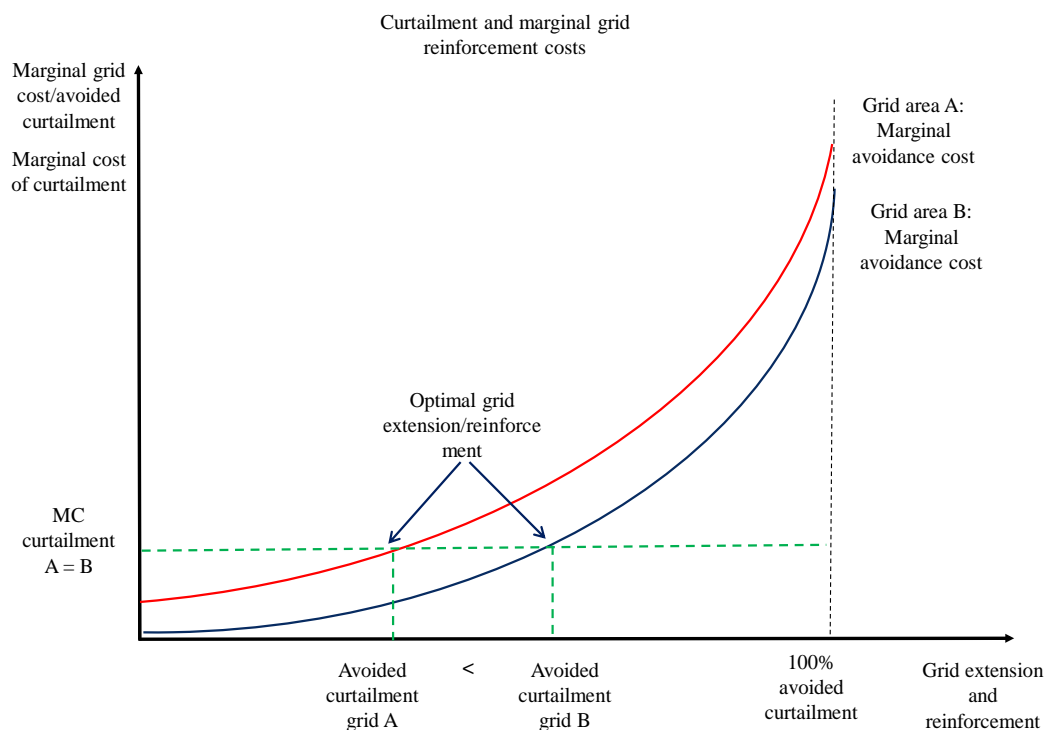


Figure 1 Curtailment and marginal grid reinforcement costs

The optimal curtailment according to Fig. 1 is at different levels in the different grids and depends on their characteristics. Grid A should have higher curtailment levels than grid B. As long as this is part of the decision parameters affecting investment decisions, this does not necessarily imply that the penetration of renewables should be lower in grid A. If the expected curtailment deviates from the optimal level, it is however important that investment incentives for generation capacity locates investment where curtailment costs for the additional investment is the lowest.

The marginal cost of avoiding curtailment in the figure reflects a static situation with a given level of fluctuating generation in the grid. If new curtailment-increasing generation capacity is added, marginal avoidance costs are, *ceteris paribus*, lower. Assuming a correct incentive structure, this induces investment in grid reinforcements, but only to the point where marginal costs equals the losses from curtailment at the new level of renewable generation capacity. For a static situation, the incentive structure may in practice be given or supervised by the application of reference network models to monitor the optimal levels of network extension and curtailment. The avoided curtailment is the accumulated amount during the lifetime of the alternative network investment. Marginal cost of curtailment can be interpreted as an average of the market price in the hours with curtailment. This is independent of the actual grid and thus, marginal curtailment costs are identical in area A and B for the same hours. This argumentation assumes that there is the same market price for generation from A and B grid instead of locational prices.

Compensation for generators

To avoid in-optimally high curtailment, compensation should be considered in all the situations where the responsible can be identified and this entity can affect the level of curtailment. We focus this section on using compensation as an incentive for implementing optimal curtailment levels and localization of new generation capacity. An overview of the most relevant real-world cases and suggested curtailment compensation levels are provided in Table 2.

Optimal curtailment levels in power systems with considerable fluctuating generation should in the long term (static) situation be determined together with optimal network capacities. If this is possible, for example by using network reference models and allowing the regulator to pass the results to the network owners instructing them to establish the optimal network level, there is no need for compensation. However, with the relatively fast change in fluctuating generation to be integrated, it will in most cases be the local network owner (DSO) that has the best knowledge about marginal grid costs and marginal curtailment from adding more fluctuating generation. A regulation that uses costs in terms of compensation payments to incentivise the DSO to invest in grid until marginal costs matches the marginal compensation payments might be a solution when there is an information bias in favour of the DSO. In this case, compensation is needed as a necessary incentive for the DSOs. In the discussion of inducing correct investment incentives for DSOs, we assume that network regulation does not allow compensation payments for curtailment to be fully included in the revenue cap for the DSO. The DSO will thus prefer a situation where the combined grid investment and curtailment costs are minimised, maximising their profits. In Table 2, these two regulatory options are treated in case 1.

The important point is to provide incentives for the DSO to invest in network capacity, until

marginal network costs = marginal expected compensation for curtailment over the lifetime of the network investment.

The lower the value of curtailed fluctuating generation and therewith the compensation payment, the higher the level of optimal curtailment will be – thus, a higher share of fluctuating generation will lead to higher levels of optimal curtailment.

Ideally, compensation fulfils both the following conditions:

- Curtailment being only partially compensated should provide DG with an incentive to invest in area where this is the least likely to happen.
- Curtailment compensation payments from the DSO to the generator should induce the DSO to invest in grid reinforcements until an optimal level is achieved.

Source of curtailment and regulatory regime		Curtailment compensation		
		generator compensation	by network company	by society
1: Network constraints (optimal curtailment)	Network constraints – no pre-agreed level of curtailment	market price – with loss of subsidy	Partially, e.g. at market price if responsible	no
	Network constraints - curtailment until pre-agreed level controlled by regulator	none below level, fully above level	none below, fully above level, if responsible	no
2: Network extension delays	Priority dispatch granted previously	yes, fully	market price part, if responsible for the delay	Fully, if lengthy permission procedures responsible for the delay; if network company responsible, only support part
	No priority – new installations	market price – with loss of subsidy	Partially, e.g. at market price if responsible for delay	Partially, e.g. at market price if lengthy permission procedures responsible for the delay
3: System security concerns	Curtailment due to general system security concerns	None, in line with emergency rules for all other generators	not responsible	no
	Curtailment specifically due to technology issue (uncontrollable sources)	market price – with loss of subsidy	not responsible	Partially, e.g. at market price if TSO preorders curtailment of certain technology
4: Excess generation (zero or negative market price)	Excess generation relative to load	market price, but this should be zero	not responsible	market price, but this should be zero
	Voluntary curtailment incentive in excess situation	only subsidy part (in excess of market price)	not responsible	Correction of incentive for zero marginal cost generators with feed-in or premiums

Table 2 Suggested compensation for different curtailment situations and in various regulatory regimes

Table 2 provides an overview of the most relevant curtailment compensation situations. We distinguish 4 sources of curtailment drawing on Table 1. Then we suggest whether there is to be no curtailment compensation, i.e. the loss is to be borne entirely by the generator, whether it has to be paid by the network company or the society in general for example financed by general system charges paid to the system operator. By the term ‘network company’, we refer primarily to a regional/local entity where network congestion may occur, whereas a system operator is responsible for overall system security concerns. Society is a generic term that could in practice be represented by the system operator, i.e. costs attributable to society could be levied on TSO charges to final customers. Compensation can be fully including the quantity based support received by renewable generators or partially based on power

market prices. If fully compensated, the DG does not have an incentive to locate the investment to less constrained grids and therefore this option is mainly for obligations regarding existing generation capacity. Next, we distinguish specific regulatory constellations. They are not exhaustive, but capture occurrences with specific relevance to renewables support and connection regulation, and are addressed in the following.

Two regulatory options to induce network investment and corresponding optimal curtailment exist as illustrated under case 1. One regulatory option addresses a case where certain maximum curtailment levels have been agreed upon before connection of new generation to DSO grids. This can be classified as a *quantity-regulatory* approach. In order to set locational incentives, these levels could differ geographically. Yet, they need to be monitored or set by regulators, e.g. with the help of network reference models. Until the pre-agreed level which is the optimal level, no compensation is to be given, whereas beyond it, the responsible party compensates fully the lost revenue. With expected and announced curtailment costs in a particular grid, the generation investment in other grids with less costly constraints would be induced. Such expected curtailment cost up to pre-agreed level can set correct locational incentives for distributed generation units. This would be an incentive similar to reducing connection costs in grids with less capacity constraints. We find that this option should be applied where the changes in both grid and fluctuating generation capacity are expected to be gradual and limited, or the majority of curtailment is expected to be due to transmission constraints.

The option in the first row differs from this regulatory solution by the virtue that the regulator does not have to set an optimal curtailment level, but that it results from an equilibrium as suggested in the previous section on involuntary curtailment and optimality. This can be classified as the alternative *price-regulatory* approach. The responsible network company gives a partial compensation that could be set at the market price level by the regulator. This results in optimal short- and long-term incentives for both DSO and new generators: building extensions is speeded up to shorten the periods with high compensation payments. In addition, permanent curtailment remains allowed in the long-term and the network company will choose them such that curtailment expenses are marginally identical with network extension costs. At the same time, the characteristic that compensation is only partial induces locational incentives to project planners. We find this option should be used when changes in network end user demand or distributed fluctuating generation are relatively large and uncertain. This regulatory option should also be preferred when curtailment is expected due to constraints in several small independent distribution grids.

As case 2, we regard network extension delays as a cause which can already impose a problem at low system penetration levels. Priority dispatch has typically been granted under feed-in tariffs. This implies that *existing* generators have based their investment decision on the right to generate whenever possible. This contractual basis remains to be served in the case of network congestion, either by full compensation distributed on the network company responsible for delays and society or entirely by compensation from society. By network extension delays we mean local grid reinforcement but exclude the delay of direct connection. New generation capacity should not be granted priority access if power markets work sufficiently well. Compensation for curtailment to new capacity should be paid partly by the responsible party at market price levels. This would induce investment where the loss from curtailment is expected to be the lowest due to anticipated delays (lost support).

If system security concerns (3) cause the curtailment, the authors suggest that no compensation is to be given if the curtailment follows the same rules as for other generator technologies. If, however, technology-specific issues such as high uncontrollable generation relative to system load legitimate the curtailment, compensation is to be paid for by the system operator.

Curtailment caused by system wide excess generation (4) can be optimal as discussed in the following section, but when this occurs there need to be incentives in place to make the highest marginal cost generation curtail output first. In case of market dominance of quantity supported renewable generation e.g feed in tariffs or premiums these generators will not curtail until the market price become negative corresponding to the support they give up. Zero cost generators should curtail before those low marginal cost generators that are characterised by high stop and start costs. By compensating renewable generators for the lost support, they will voluntarily curtail generation at a market price of zero as discussed in the following section on voluntary curtailment. This type of compensation is only relevant if there is not enough zero cost generation that curtails at market prices around zero.

In conclusion, we advocate compensation at different levels for a number of cases. These are pragmatic suggestions balancing the desire for locational incentives for generators and to induce the network operator to achieve an optimal curtailment level. We generally prefer compensation at market prices when the curtailment is due to constraints in the network and no compensation when the curtailment is due to overall excess generation and all generators are treated similarly.

Voluntary curtailment and optimality

In the case of a generator maximising his profits, voluntary curtailment means that curtailment is a private optimal solution given the constraints he is facing. The issue is then if this private optimality also corresponds to a social optimal situation. In general, as the renewable low marginal cost generators are receiving production based support (case I and II below), the curtailment is also social-economically optimal if it is privately optimal. The problem is that it is necessary to have negative prices if a renewable generator should voluntarily give up the production support earned from feed-in tariffs or premiums.

Three types of renewable generators support and incentives can be distinguished:

- I. Full fixed feed-in support (no dependence on market price)
- II. Feed-in premium + market price
- III. Market price only (beyond support period, or in markets without support)

Figure 2 illustrates how these three types of zero marginal cost generators enters the short term supply curve at different levels depending on the support level. Fixed feed-in supported generators will supply until the negative market price equals the quantity based support they receive. Even if they don't participate in the market the responsible (TSO or handling agent) will pay the support and instruct the generator to reduce supply (curtail) at this price level. Renewable generators with premium will supply at less negative price and zero cost renewable generators without support will supply at zero price.

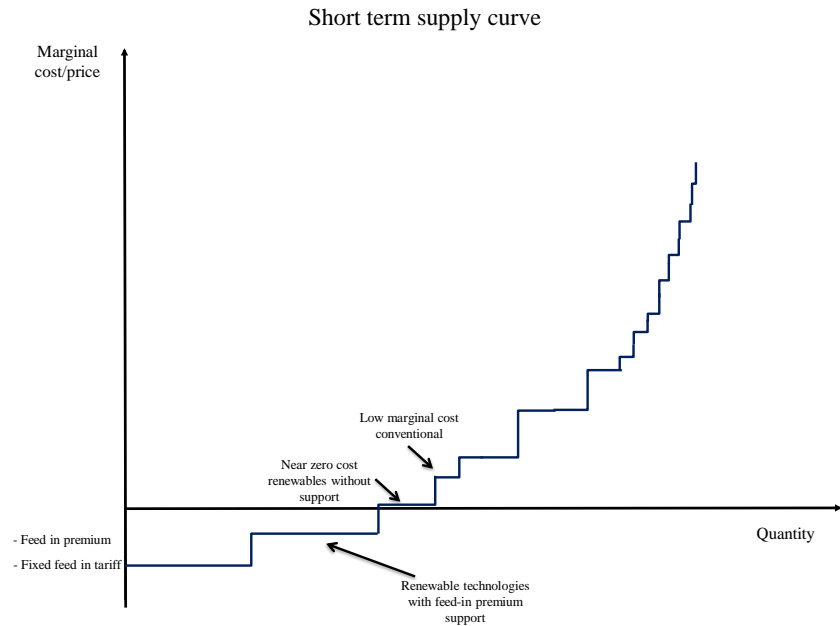


Figure 2 Short term supply curve with quantity based support for renewable technologies

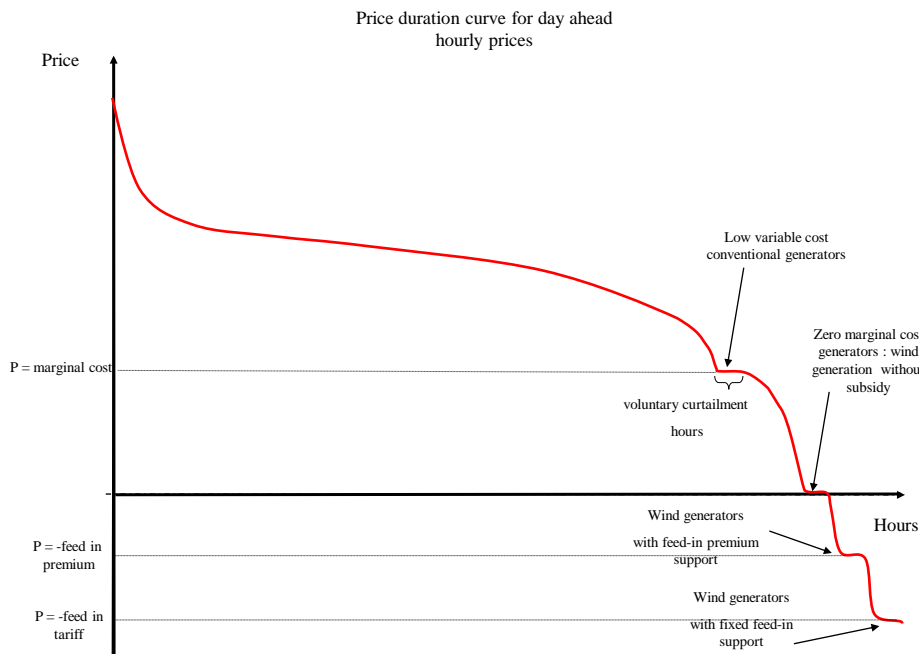


Figure 3 Voluntary curtailment and the price duration curve

Figure 3 depicts an exemplary annual price duration curve. The flat parts illustrated in Figure 3 correspond the short term supply curve with flat parts for certain technologies as corresponding to levels given in Figure 2 . Normally the fluctuating wind and PV technologies will be represented by the

zero marginal costs and therefore enter the simplified supply curve first. However, including loss of support from feed-in tariffs etc. should place these technologies with a flat supply at negative prices. This is observed in some markets today, but other markets do not publish these supply bids and therefore this behaviour can only be observed in the flat parts of the price duration curves. In Nicolosi (2011) this is illustrated in modelling scenarios including voluntary curtailment, forced curtailment at zero price and forced curtailment at -150€/MWh that weakens the priority feed-in primacy under a feed-in tariff.

Avoiding wind curtailment with storage capacity is a very relevant option in systems with a high fluctuating share. The high price volatility provides even without zero and negative prices associated with curtailment incentives to invest in storage capacity. With more storage capacity, wind curtailment due to excess generation on the market will be reduced. All the market price related price volatility is included in the investment decision. The non-market curtailment (local grid constraint or emergency reserve) should add to the profitability of investing in storage. This means storage investment in the DSO grid could become relevant if storage technologies here are competitive to storage elsewhere in the system. In Denmark this will probably not be the common situation as competitive storage is still mostly associated with hydropower in Norway, but the alternative of electricity based heating with heat storage in grids with constraints that lead to wind curtailment is relevant.

Asymmetry of balancing costs and voluntary curtailment

Skytte (1999) pointed to the asymmetry of regulating costs between up regulation and down regulation premiums and the impact on bidding incentives for balance responsible generators. With an estimated equation for up- and down-regulation prices in the Oslo area of the Nordic market, he found that down-regulation premiums are lower than up-regulation premiums. Other markets do not necessarily show the same pattern, as this depends very much on the composition of technologies, imbalance charge and regulating market design. This possible asymmetry provides an incentive to bid less than expected output at the day ahead market and on average, realise more excess generation than deficit generation (Zugno et. al. , 2010). This holds for both a positive and negative correlation between wind generator and overall system deviations relative to their schedules. A comprehensive analysis of the properties of the different price schemes for balancing markets and the incentives for generators are given by Vandezande et. al. (2010). Here we focus on the different sources of asymmetry that provide incentives for voluntary curtailment.

For a system with a single price for up and down regulation, the situation is illustrated in Figure 4.

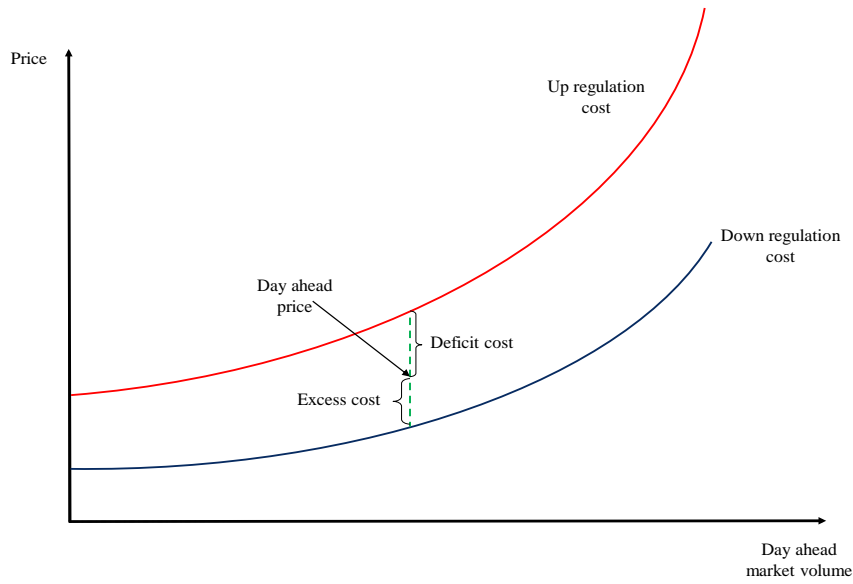


Figure 4 Asymmetrical balancing costs due to the convexity of the supply curve

In a system with a single imbalance price system, the asymmetry is due to that the upwards regulation are right hand costs and downwards regulation are left hand costs of the supply curve. The asymmetry is illustrated in the figure above with the vertical distance from the day ahead price level. To balance the asymmetry, the generator will have to end in the excess generation situation as he is incurring the lowest balancing cost here. It could for example be optimal to have 2/3 probability for experiencing an excess in real time and only 1/3 for experiencing a deficit. That will be achieved by bidding less than actually expected generation at the day-ahead market, which eventually corresponds to voluntary curtailment in a number of instances (Zugno et. al., 2010).

Furthermore, the largest absolute supply deviations due to fluctuating generation can be expected when generation from these sources is high. The market prices in these situations will at the same time be considerably influenced by this supply at near zero costs (Jacobsen and Zvingilaite, 2010, Andor et. al., 2010) and this might further induce voluntary curtailment due to asymmetrical balancing cost under low day ahead prices. In general, the price of down regulation is more correlated with the spot price than is the price of up-regulation (Skytte, 1999). By down-regulating the loss is the sales revenue from the spot market reduced by any possible saved fuel.

4. Quantitative case studies

Involuntary curtailment in Germany

Germany is among the largest wind energy markets of the world. Electricity demand centres are chiefly in the West and the South, whereas wind is mainly sited in the Northern coastal regions and the East. As the planning and permission procurement procedures for network extensions are typically longer than for wind farms, congestion in the high wind penetration regions is handled by curtailment as a means of last resort after other measures have been taken. If the curtailment is due to system stability concerns at the transmission level, no compensation is given; if the curtailment is due to network congestion, generators are to be compensated for their foregone income. The obliged network operators need to

prove that all other measures were taken in order to be allowed to recover curtailment compensation expenses through network charges.

An in-depth review of the current legal situation in Germany can e.g. be found in Brandstätt et al. (2010), who analyse the economic effects of curtailment on German wind generators under the existing feed-in tariff regime. They propose to change the existing scheme of possible involuntary curtailment towards a scheme of voluntary curtailment in the context of negative electricity exchange prices. Generators should always have the right to produce at their respective feed-in tariff, and network operators can buy voluntary curtailment by means of a tendering scheme. This leads to a situation where curtailed generation is remunerated at prices higher than feed-in tariffs, while negative price spikes are avoided. Such a scheme would foster the investment in additional wind capacity. The proposal minimises investment risk for the wind farm operator, but does not address the far more often occurring curtailment due to network congestion.

Curtailment data for a number of network regions can be retrieved from the operator of the 110 kilovolt grid in the North Sea coastal region with high wind penetration (eon Netz GmbH). It shows that congestion occurs mainly at this voltage level. During 2010, only 10 instances of curtailment are reported due to restrictions at higher voltage levels and only one instance due to congestion at lower levels.

Figure 5 displays the number of hours with curtailment to a certain level in 2010. The regarded grid in Northwestern Germany is subdivided into several curtailment zones at the 110 kV voltage level. 43% of all curtailments in Germany occurred in this grid during 2009 (Bömer et al., 2011), which is why it is in the focus of this analysis. The figure shows the number of events in a specific hour, e.g. curtailment to 60%, 30% or only 0% of capacity as well as when curtailment was finished (i.e. 100% permitted again). The maximum curtailment in one of the sub-zones is taken as basis for calculation of the figure. It is clearly visible that a disproportionally large amount of curtailment activation falls into the afternoon hours, followed by a high number of ended curtailments in the early evening hours. This reflects the diurnal wind pattern where afternoon generation exceeds night generation by 20%. The average duration of aggregated curtailment of all zones is at 5-6 hours. The distribution of curtailment is not even between the regarded zones: in a few zones, slight curtailment occurs only in few hours a year, while the most heavily affected zone is subject to 480 hours with full curtailment down to 0% in 2010. For the respective wind farm operators, compensation payments can therefore expected to comprise a considerable share of their income. The share of curtailed wind generation in Germany was at about 0.2% in 2009 (Bömer et al., 2011). Despite the efforts of network reinforcement, the curtailed amount cannot be expected to decrease substantially due to new wind installations and repowering of older units. Figure 6 shows wind generation in all hours of the year in the TenneT control zone in Germany and hours subject to curtailment during 2010. The high number of curtailment hours even at low wind generation in the control zone illustrates that curtailment is a highly local issue. Thus, curtailment is independent of overall wind generation: the average value of wind generation and the average value of curtailed wind are similar. However, both are lower than average market prices due to the merit-order effect. In conclusion, curtailment in Germany happens predominantly involuntarily and because of network congestion at the 110 kV voltage level. Generators are to be compensated in this case, whereas they receive no payments if the generation reductions were due to concerns about overall system stability. This provides comparatively stable investment conditions for RES operators, but locational incentives are rather limited and only due to facing the risk that not the full foregone production amount is compensated for. With Germany progressing towards a voluntary price premium scheme from 2012 onwards, the authors expect that the involuntary curtailment presented here will be partially replaced with voluntary curtailment.

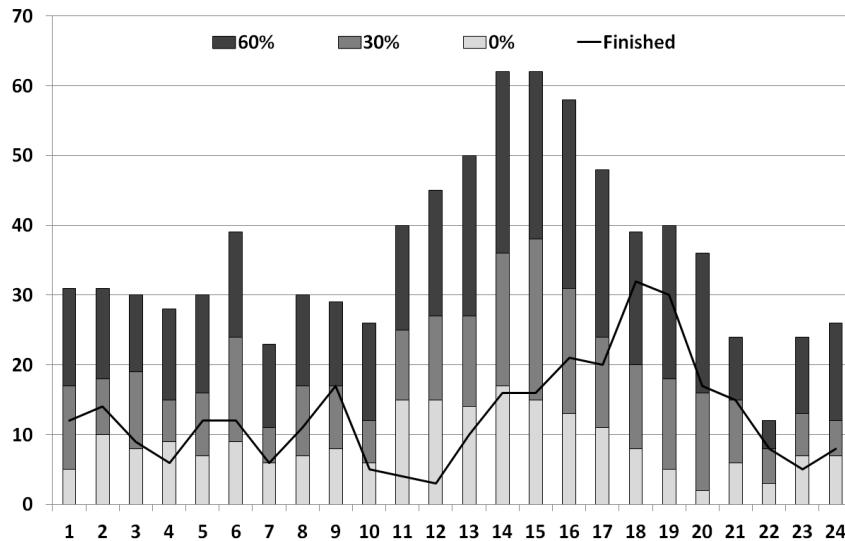


Figure 5: Number of hours when curtailment to a certain level was effectuated in Northwestern Germany (eon Netz GmbH), 2010

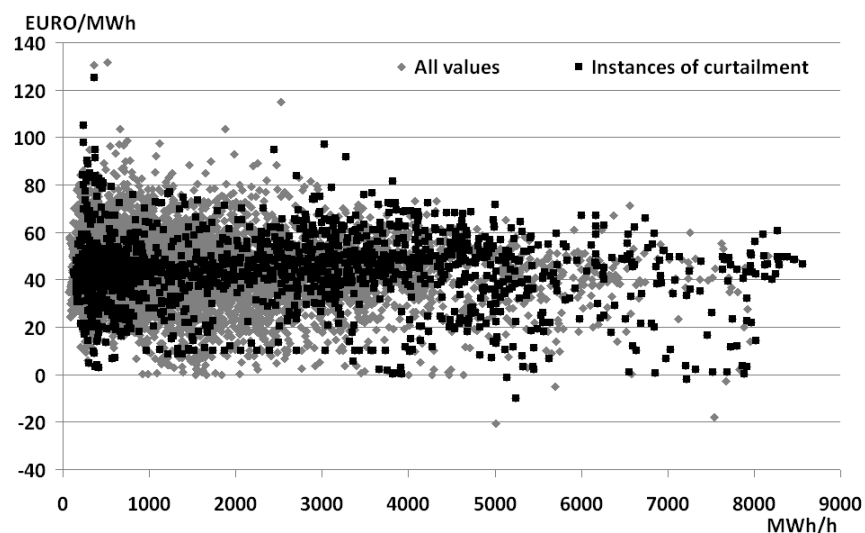


Figure 6 Wind generation in the German TenneT area and respective electricity prices, 2010 - all hours and hours with curtailment

Involuntary curtailment in Spain

Involuntary curtailment in Spain is categorised according to the following reasons: transmission network congestion, distribution network congestion, voltage dips and excess generation. The last point is more severe in Spain than in a number of other European countries due to the comparatively weak interconnections of the Iberian system with France. A minimum share of conventional generation necessary for system stability is determined by the TSO and wind generation affecting this minimum share may be curtailed. Revuelta (2011) gives an example where this minimum share exceeds 10 GW, corresponding to more than 1/3 in single hours. Between 2008 and 2010, total curtailment varied between approx. 70 and 250 GWh (Duvison García, 2010). However, the reasons changed considerably: voltage dips were the main reason in 2008, followed by congestion at the transmission level, while distribution congestion and excess generation played only a minor role. This picture changed in 2009

and 2010, when distribution congestion and excess generation, respectively, were the main reasons. This is illustrated in Figure 7, and the share of MWh curtailed in the first 3 quarters of 2010 adds up to approximately 1% of possible generation. For 2020, the Spanish TSO expects a curtailment of 3.6 TWh/year, amounting to about 5% of possible wind generation (Duvison García, 2010).

If the curtailments were announced before the closure of the day-ahead market, no compensation is given. Later restrictions are remunerated at 15% of the spot market price without the feed-in premium (Rogers et al., 2010). In conclusion, the reasons for curtailment changed over the last years, with excess generation concerns being the main reason in 2010.

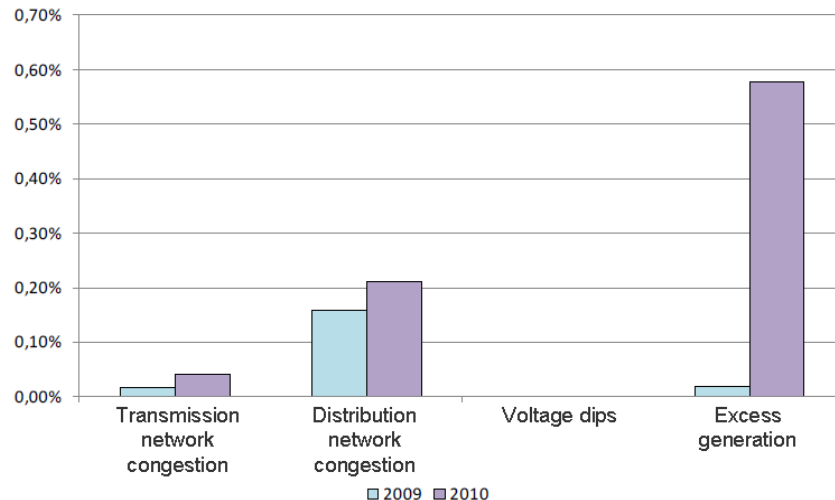
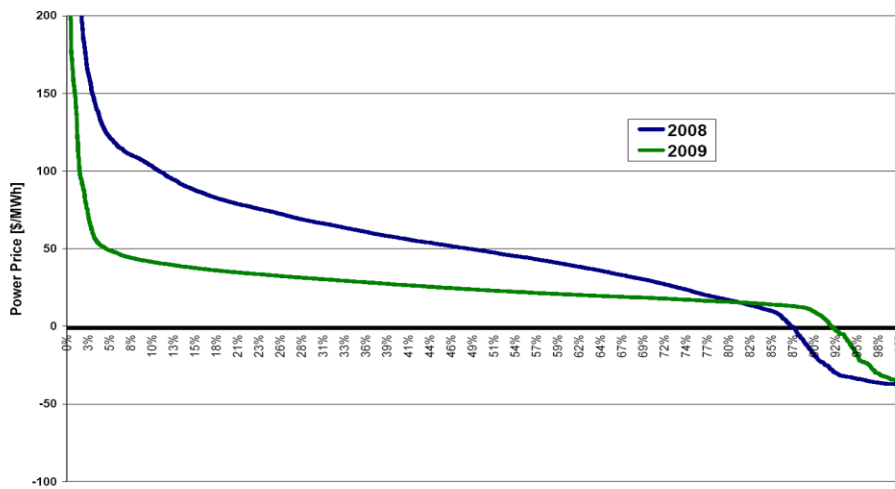


Figure 7 Share of MWh curtailed in Spain. 2010 values cover the time period until 30/09/2010. (Duvison García, 2010)

Voluntary short term curtailment and market prices – incentives and indications

Voluntary curtailment appears in the price duration curves as illustrated in Figure 3. The flat parts at zero or negative prices reflect a marginal technology with identical costs, e.g. wind that receives a production subsidy. The flat parts might also include hours where other technologies are marginal at the same level. The case of Texas, 2009, illustrates this where curtailment due to grid constraints reduces the voluntary curtailment seen in 2008 (value of production tax credit, see Figure 8).

Price duration curves – Texas west



Source: ERCOT (2010)

Figure 8 Price duration curves for Texas indicate voluntary curtailment at negative price levels (reproduced from Nicolosi, 2010)

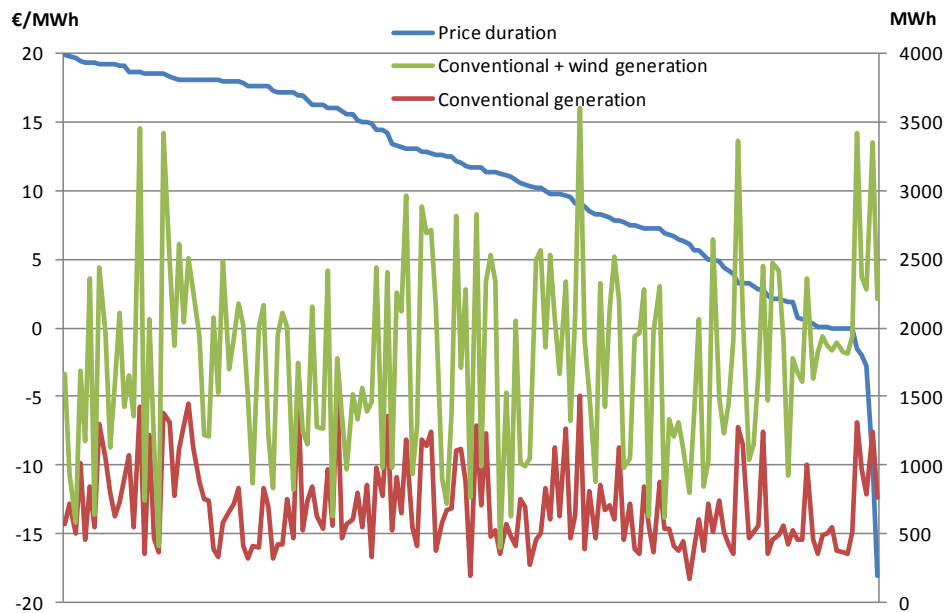


Figure 9 Price duration curves for Western Denmark in 2010 indicating a small amount of voluntary curtailment at zero prices (165 lowest price hours, sorted according to the price duration curve)

Examining market prices in Western Denmark in 2010 (Figure 9) reveals that only very few hours show zero prices and that there is no negative price level reflecting the feed-in tariff or premium level. In the future with much more wind capacity in Denmark, the flat part at zero price is expected to cover a larger number of hours.

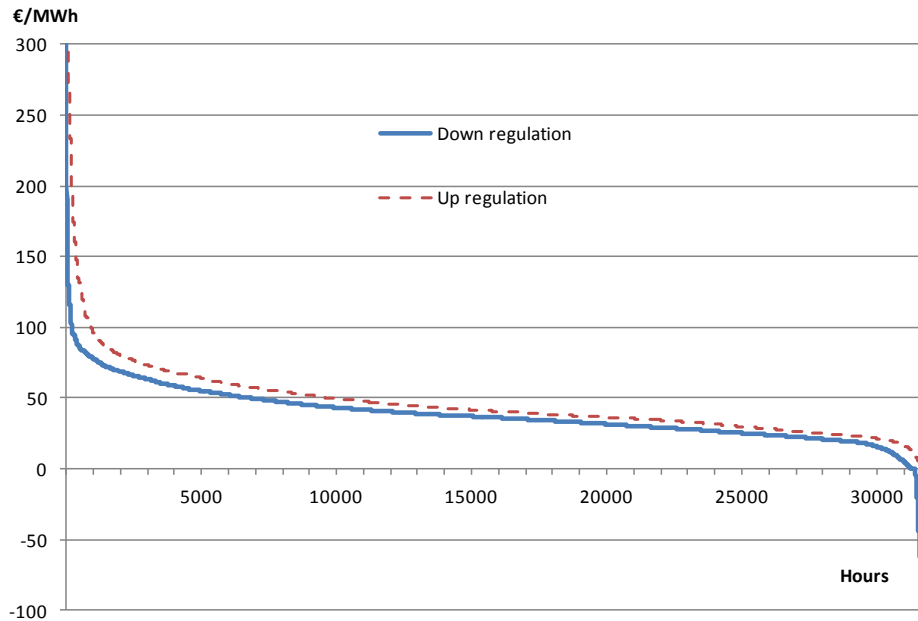


Figure 10 Duration curve for hourly up- and down-regulation prices in West Denmark, June 2006 - December 2009

The illustration of up and down regulation prices over a period of 3½ years in Figure 10 reveals that up-regulation prices are higher and that the duration curve for down regulation contains more hours with low and even negative prices. The two curves are not corresponding in time along the x axes, but as duration curves. The up regulation curve is steeper than the down regulation curve for high prices and flatter than the down regulation for low prices. This suggests that the asymmetry between balancing costs will be most pronounced at high and low prices and much smaller for the majority of hours in the middle. Incentives for voluntary curtailment will thus be most pronounced in the high price and low price areas.

5. Discussion: What are the economic costs and benefits of curtailment?

An obvious policy ambition is to achieve a level of curtailment that balances social benefits with costs. This will require that costs and benefits can actually be assessed. We have identified categories of curtailment in Table 1 which can all contribute to total optimal curtailment. Some of these will be partly overlapping, but in general they occur at different times. From a theoretical perspective, curtailment should take place up to the point where the marginal cost of avoiding this curtailment equals the marginal value of spilled energy, but both the marginal costs of avoiding and especially the value of the spilled renewable generation is difficult to quantify.

The private cost of curtailment depends on the support scheme generators are entitled to, specific rules regarding curtailment and compensation and possibly the power market price. Compensation could be granted based on escaped income or the marginal value of the generation. In the first case, the specific compensation rate is constant under a feed-in tariff scheme and price-dependent under premium and TGC schemes. In the latter case, it always depends on market prices.

If income is only based on power market prices, higher curtailment rates are acceptable. In this case, the implicit incentive for wind investment is lower than if additional income from a support scheme is taken into account as well. Granting support compensation may be based on the criterion of the replaced marginal technology, i.e. only if CO₂-emitting generation is replaced and thus, one of the goals of the

support scheme is achieved. If this criterion is applied or the subsidy beyond market prices is not compensated for at all, the incentive to invest in fluctuating RES is decreased.

Socio-economic benefits of allowing curtailment amount mostly to avoided investment costs and avoided operational costs. Avoided investment costs are mainly associated with not building additional grid capacity only needed for a few hours annually. Avoided operational costs cover lower systems reserves procurement as well as buying less regulating energy from partly inflexible conventional units. Furthermore, reduced adjustment costs in case of emergency faults as well as the expected value of avoided consumer disconnections account as avoided operational costs.

In practice, optimal socio-economic curtailment is expected to be rather low (max. 1-2% of possible generation) even in grids with relatively high shares of fluctuating generation. Grid constraints curtailment would involve very few distribution grids in Denmark – the grids with high generation to load levels are few and capacities in general high. Higher levels of optimal curtailment might be determined if a connection is erected exclusively for one project and the connection investment amounts to a considerable share of the RES project investment. This is typically the case for offshore wind farms. For the UK, it is estimated that dimensioning the offshore wind farm on average at 112% of the installed generation capacity leads to an optimal result (National Grid, 2009).

6. Concluding remarks

This article analyses a number of different constellations leading to involuntary and voluntary curtailment. Curtailment can be a rational option to deter generation investments where grid integration costs are very high, or simply to avoid high grid investment cost by accepting a marginal curtailment (loss) of generation when we are expanding the renewable fluctuating generation capacity. Accepting this approach can lead to a more cost-efficient deployment and system integration of RES generators. Avoiding curtailment completely would make it extremely expensive to reach a high share of fluctuating renewable generation. Ideally curtailment should take place up to the point where the marginal cost of avoiding this curtailment equals the marginal value of spilled energy. We find that both in the short and the long run situation curtailment can be an optimal solution. The short and the long run optimal levels of curtailment will normally differ due to time delays in adjusting capacity, lumpiness of network investments and changing conditions regarding reliability and system security.

Efficient levels of infrastructure investment with fluctuating generation depend on the marginal grid costs and these differ strongly between areas and between on-shore and off-shore grids. Naturally, this should affect the optimal level of expected curtailment in the areas, with less grid capacity off-shore and more expected curtailment as well. This involuntary curtailment should be a regulated option that compensates the generator at least corresponding to the market price of electricity.

Efficient location of new capacity within a market is accomplished with DSOs providing incentives for generators to invest, where integration costs are the lowest – if grid capacity is a constraint, costs in terms of risk of curtailment loss should be included in the investment localisation decision.

For the regulatory policy the recommendation is thus to allow curtailment by DSOs or the TSO, but the question is whether to compensate generators at their full income, i.e. including support, or at market prices. A compensation at the level of the market price secures incentives for DSOs to invest in grid capacity up to the point of expected costs of curtailment under a regulatory regime that leaves this decision to the DSO. At the same time, the expected loss from incomplete compensation would assure that investors locate their investment, where the least curtailment is expected. Compensation regulation exists in some markets such as Germany, but rules differ among markets.

The authors expect that curtailment will be highest in association with offshore wind, where connection costs are high. In the future, an increasing share of connections will be off-shore and the investment in connection capacity should assure that there will be less than full capacity for these. Total curtailment is low in most markets, but rising with RES shares and in some regions as in the German example can be substantial. For Denmark the curtailment is very modest with less than 0.5% of annual production hours affected corresponding to around 0.1% of total fluctuating generation. Emergency curtailment is very modest in DK as the interconnection capacities are very strong and the very huge disconnection of wind turbines in short time happens very rarely. Also the introduction of negative prices has contributed to reduced supply from conventional generation in the relevant hours.

An opportunity for the least-cost integration of renewable generation can be achieved by envisaging curtailment where, until today, connection of renewable generation takes place at nameplate capacity. For example, additional offshore wind farms could be installed at existing sites without major transmission grid reinforcement if curtailment was allowed. Existing or planned installations in a number of countries like Germany and Denmark could be extended by 10-15% of installed capacity by aiming at optimal curtailment as was concluded in the UK study.

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